BRIEFING

OVERVIEW

OF

THE ALBERTA ELECTRIC SYSTEM

&

THE ELECTRIC ENERGY MARKETING ACT (EEMA)

Prepared For
The EEMA Review Panel

Prepared By
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Alberta Department of Energy
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OVERVIEW
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A. Overview of Alberta's Electrical Industry

Description of Alberta's electric utilities and service areas

- As shown on table 1, Alberta has a mix of investor-owned and municipally-owned electrical utilities. Four of Alberta's electrical utilities are fully integrated since they generate electricity and provide bulk transmission and distribution service to final consumers (figure 1). The remaining utilities purchase power wholesale from TransAlta Utilities (TAU) and provide distribution service to final consumers.

- Each utility has an obligation to provide electrical service to consumers in service areas[1] approved by the Energy Resources Conservation Board (ERCB). For example, the City of Edmonton owns and operates Edmonton Power, a fully integrated electric utility, which serves customers within its corporate limits. The current service areas of the utilities roughly correspond to the historical development of the utilities and result from the diverse ownership of Alberta's electrical industry. On the other hand, most provinces in Canada have one Crown-owned electrical utility responsible for the generation and transmission of electricity. Distribution to final consumers is provided by the provincial utility and by municipal utilities.

- Alberta's electrical facilities are operated as a single integrated system with the exception of isolated facilities and those owned by Medicine Hat. The daily production of energy is coordinated in order to minimize the cost of producing electricity. Coal-fired plants (figure 2) have, traditionally, been the most economical source of base load power[2] and therefore, provide 89 percent of the electrical load[3] in the province (figure 3). In addition, there are a limited number of gas-fired plants and hydro facilities. The base load generating plants are utilized first and then the gas-fired and hydro plants are brought on stream as the system reaches peak load[4] (figure 4).

---

1 Service area is the territory in which a utility company has the right to supply or make available its utility service.

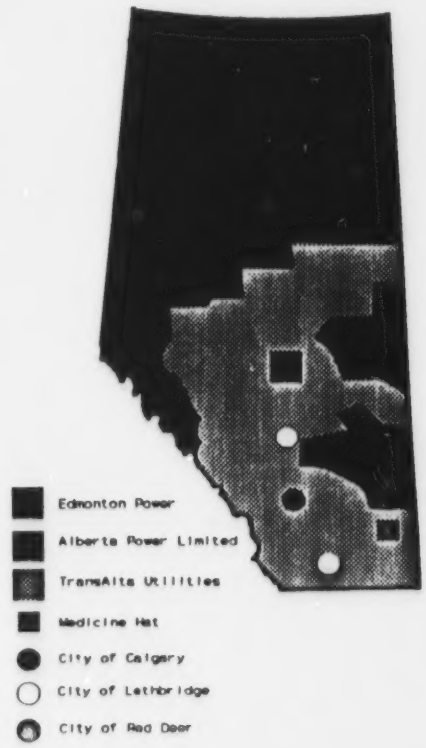
2 Base load refers to the nearly steady level of demand on a utility system. Base load generating plants generally have lower fuel costs and higher capital costs (e.g. coal-fired plant).

3 Load is the total electrical demand for service on a utility system at any given time.

4 Peaking load is the maximum electrical load consumed or produced in a stated period of time. Generating units used to meet peak load generally have higher fuel costs and lower capital costs.

BREAKDOWN OF ALBERTA ELECTRIC UTILITY INDUSTRY - 1990

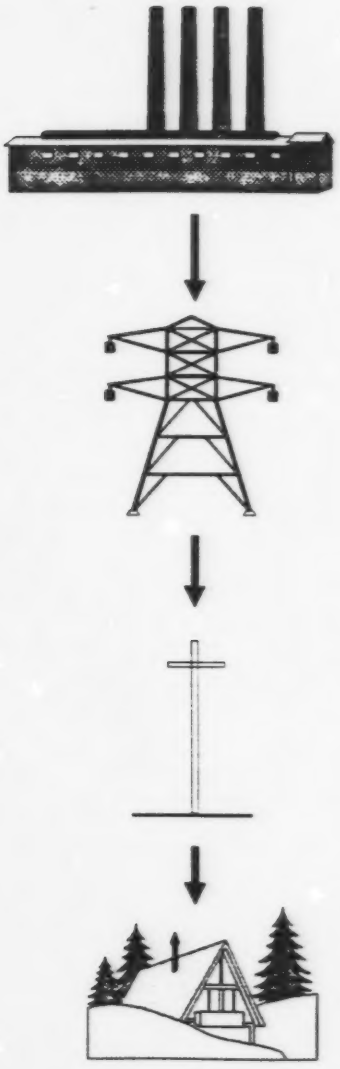
GENERATING UTILITIES	***Type***	***AIS[1] Generating Capacity[2]***	***%***	***Peak Load (1990)***	***%***
TransAlta Utilities	Investor-owned	4472 MW[3]	62	3808 MW	63
Alberta Power	Investor-owned	1340 MW[3]	18	1169 MW	19
Edmonton Power	Municipal	1299 MW	18	1022 MW	17
Medicine Hat	Municipal	160 MW	2	93 MW	1
Total Generating Utilities		7271 MW		6092 MW	
DISTRIBUTING[4] UTILITIES				(Included in TransAlta's Peak Load)	
City of Calgary	Municipal	-		1062 MW	
City of Lethbridge	Municipal	-		101 MW	
City of Red Deer	Municipal	-		89 MW	



1. Alberta Interconnected System
2. Industry generates approximately 749 MW for its own use which is not included under the utilities' capacity.
3. Includes second Sheerness unit.
4. Ponoka, Fort Macleod, Cardston, and Municipality of Crowsnest Pass also own distribution systems. Wholesale Power is purchased from TransAlta Utilities.

Table 1

FULLY INTEGRATED UTILITIES



GENERATION

TRANSMISSION

DISTRIBUTION

CUSTOMER

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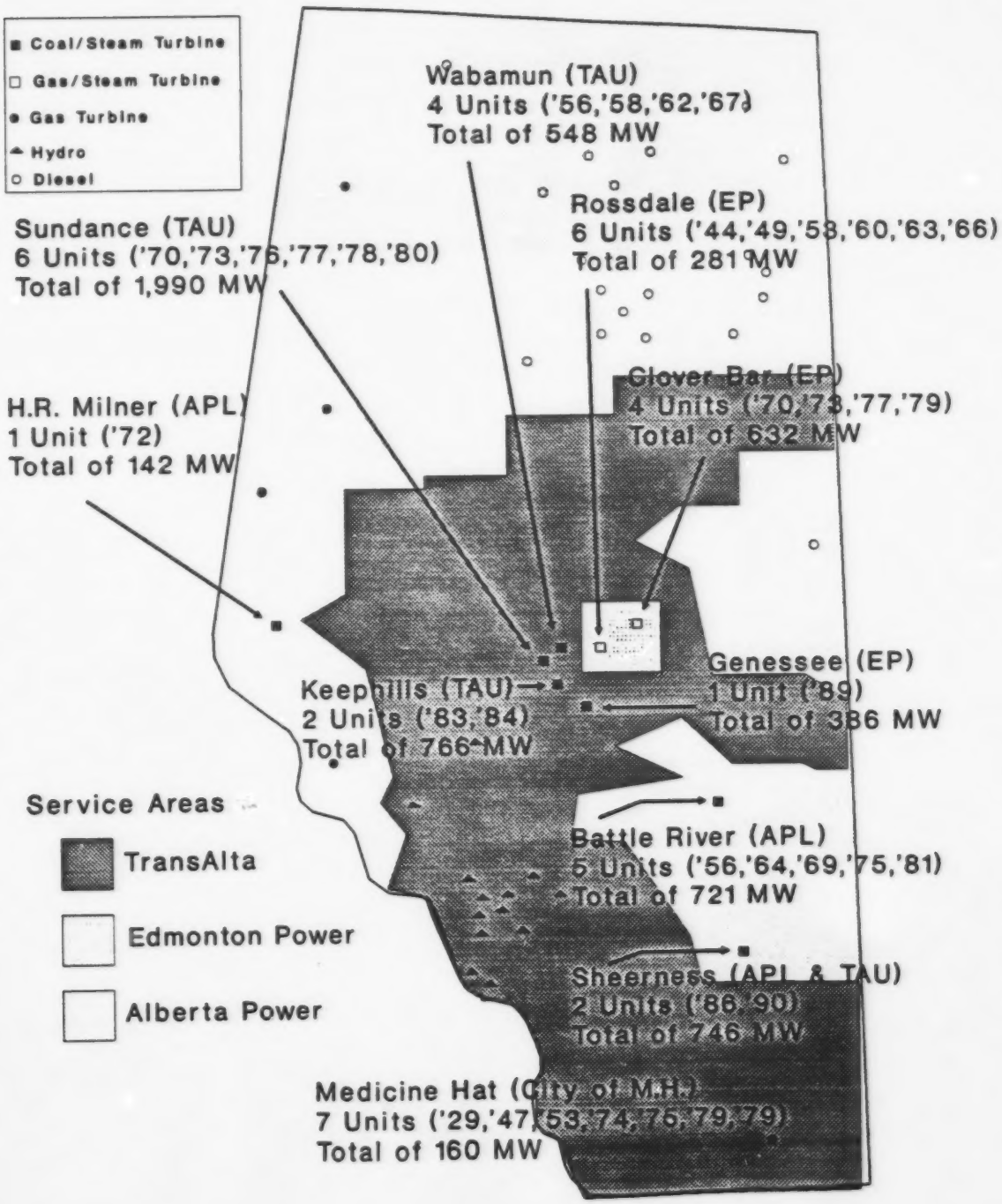
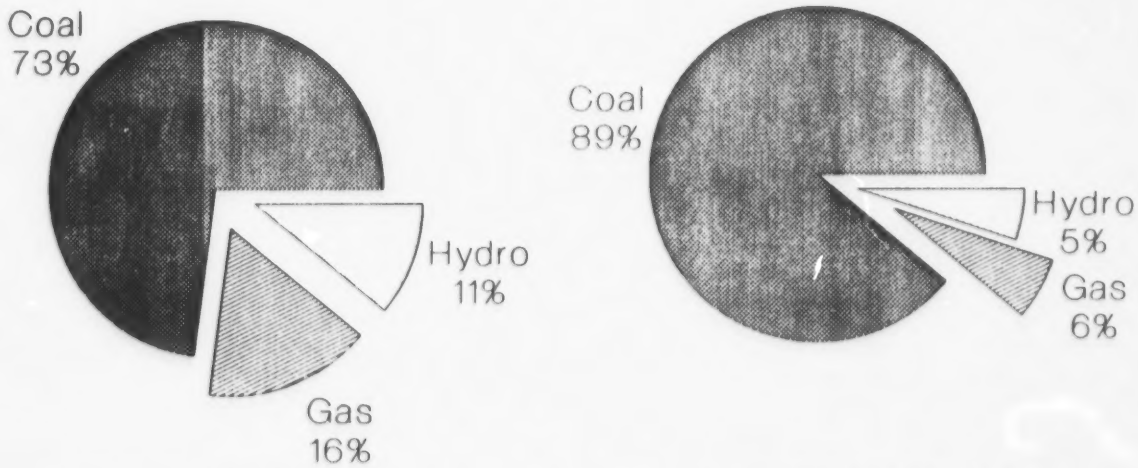
ALBERTA DEPARTMENT OF ENERGY
August 14, 1991

Location of Generating Plants in Alberta



CAPACITY AND GENERATION
% SHARE BY FUEL TYPE
1990



Source: Alberta Electric Industry Annual Statistics, ERCB

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January 1992

Figure 3

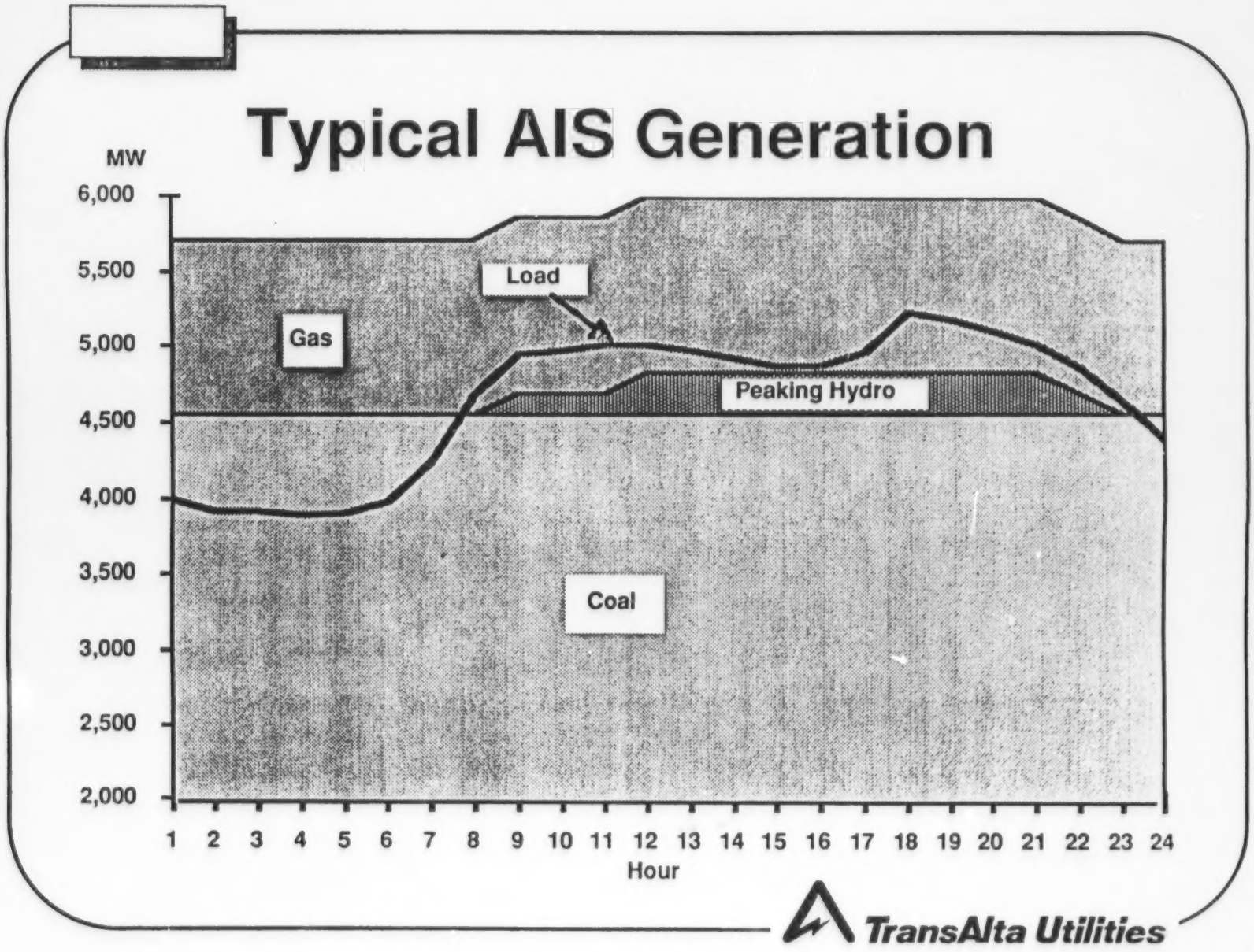
Typical AIS Generation
MW
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
Load
Gas
Peaking Hydro
Coal
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
TransAlta Utilities

Figure 4

Differences in the utilities' cost of service

- The utilities recover their cost of providing electrical service through published electrical rates. An electrical rate represents a utility's average cost to provide service for consumers within that particular rate class (e.g. residential, small general service, industrial, irrigation, etc). For example, all TAU's residential consumers have the same electrical rate regardless of their location in TAU's service area. However, residential rates vary between utilities due to a number of factors such as differences in distribution costs and timing of rate changes.

- A utility's cost of providing service is a function of its service area: the geographical characteristics, population density and available fuel sources. Cost of service also depends on the growth in the utility's service area and the additional facilities required. Alberta Power Limited (APL) has newer generation and transmission facilities since its load has grown faster than TAU's since 1982. These facilities have higher book costs due to inflation and minimal depreciation. TAU has lower generation costs than Edmonton because Edmonton Power's first Genesee unit is a relatively new power plant and accounts for the majority of Edmonton's generation costs.

- A utility's cost of service is one of the factors contributing to differences between electrical rates for similar consumers located in different service areas (the other factors are explained later under "Differences in Electrical Rates with EEMA"). Prior to the implementation of the Electric Energy Marketing Act (EEMA), APL's residential consumers had rates up to 50% higher than TAU's. Service area boundaries, which are arbitrary due to the utilities' pattern of historical growth, determine the power supplier for consumers in Alberta. It is possible for residents in neighbouring towns to have different power suppliers and therefore different electrical rates.

Regulation of Alberta's electrical industry

The basic objective of electricity regulation is to ensure that safe and reliable electricity is supplied in an environmentally responsible manner at lowest cost recovered from consumers in a fair and equitable manner. In other words, regulation establishes the broadly defined performance and pricing standards of the electric power industry.

Energy Resources Conservation Board (ERCB)

- The ERCB is responsible for recommending generating plants that are required to meet Alberta's forecast electrical requirements. The ERCB evaluates the projects based on the lowest lifetime cost, while satisfying other public interest criteria and ensuring the orderly economic development of resources in the province under the Hydro and Electric Energy Act. Recommendations by the ERCB require final approval by the provincial cabinet for generating plants over 15 megawatts (MW).

- The ERCB is also responsible for issuing permits for the development of transmission lines and for approving proposed changes in the utilities' service areas.

Public Utilities Board (PUB)

- The PUB is responsible for the setting of consumer rates of the investor-owned utilities and for approving costs pooled under the EEMA. The PUB process gives intervenors an opportunity to scrutinize the rate increases and make recommendations to the PUB. General Rate Applications (GRAs) can be initiated by the investor-owned utilities, consumer interest groups or the PUB itself. TAU and APL are currently in the process of GRAs that will be completed later this year.

- Rates are fixed by the PUB on a forecast, or "forward-looking", basis. This provides an incentive for the utility to reduce its costs when electrical rates are fixed, thereby increasing the return to its shareholders. Any cost reductions are then taken into account in the subsequent GRA.

- GRAs are completed in two phases. In phase I, the PUB approves the investor-owned utility's revenue requirements which include depreciation allowance, income taxes, operating costs and an opportunity to earn a fair return (figure 5). The following is a description of the PUB's procedure for approving a utility's revenue requirements:

  - Before a utility can recover its costs from rates, it must apply to the PUB for inclusion of the costs of facilities in rate base[5]. Accumulated depreciation is deducted from the gross rate base to arrive at the net rate base for rate purposes. The PUB determines when facilities will be included in rate base, whether costs are prudent and the appropriate rate of depreciation.

  - Following the determination of rate base, the PUB sets a fair return that ensures the utility has appropriate coverage of debt interest and can maintain financial integrity. The rate of return is applied to the utility's net rate base.

  - The utility's income taxes and operating costs are determined and added to the allowed depreciation and return to arrive at the total revenue requirements.[6]

  This completes the first phase of a utility's rate application. Procedures for approval of TAU's, APL's and Edmonton Power's costs that are pooled under EEMA are essentially the same.

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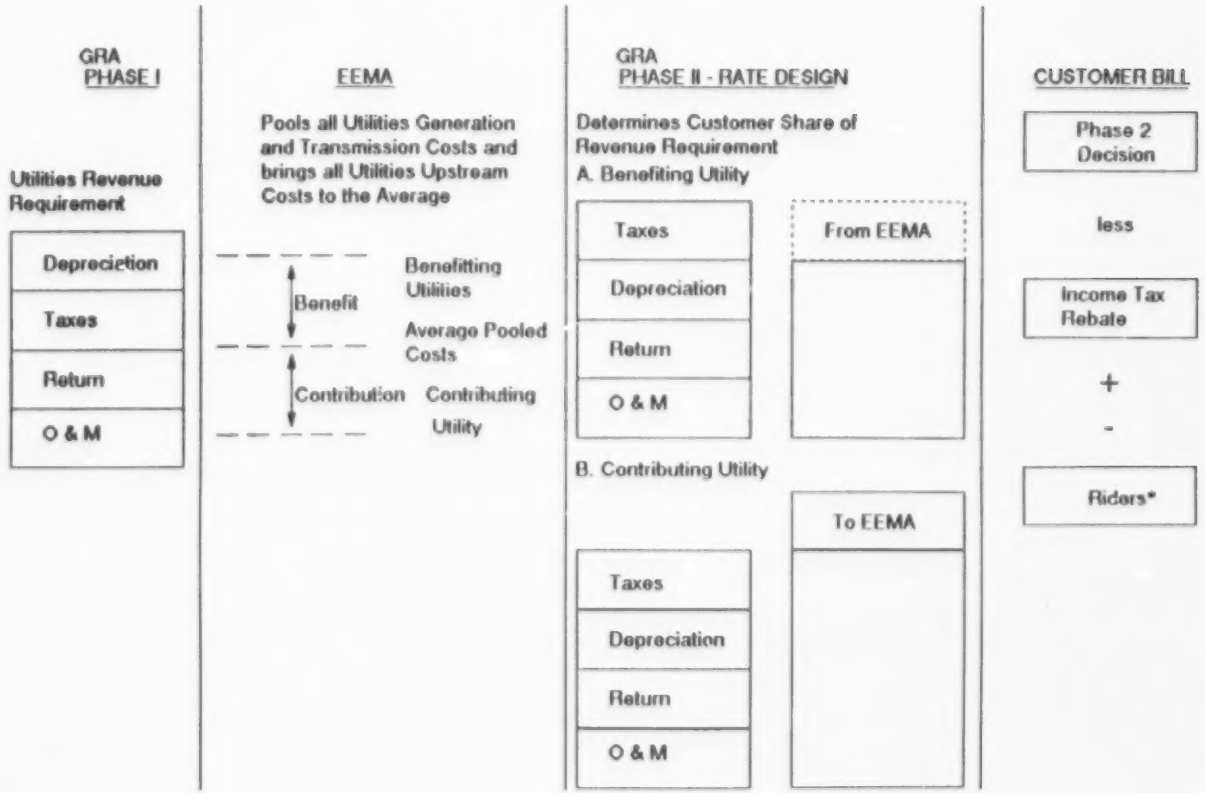
[5] In general terms, rate base is the value of plant, property and equipment as allowed by the PUB for rate-making purposes.

[6] The majority (95%) of the federal portion of income taxes are rebated back to consumers.

General Rate Application (GRA) and Customer Bill



* Riders are temporary percentage increases or decreases to consumer rates.

Electricity Policy
Alberta Department of Energy
January 1992

Figure 5

- In phase II the investor-owned utility is directed to set the necessary rates to recover its revenue requirements. Each rate is designed based on a number of criteria, including:

  - recovering the utility's total costs;
  - maintaining consistency with the relative cost of providing service to individual rate classes;
  - satisfying the customer;
  - ensuring competitiveness with electrical rates of other utilities for similar customers;
  - encouraging optimum use of electricity; and,
  - ensuring electrical rates are predictable and relatively stable.

- The weight given to a specific criterion in designing a rate depends on the characteristics of that particular customer class. Encouraging the optimum use of electricity is given more weight with industrial customers who have a greater incentive to respond to pricing signals (due to the size of their electrical bills). As a result, the magnitude of changes from rate class to rate class varies. For example, the PUB determined that TAU had an overall average decrease in its revenue requirements of 1.1% in the phase I portion of its 1990 GRA. After the phase II portion, TAU's small general service rate decreased 11% while its residential rate increased 4%.

- One of the primary criterion for all rate classes is the relative cost of providing service to the individual rate class. For example, it is more costly to provide service to residential consumers than industrial consumers:

  - Extensive distribution facilities are required to provide service to individual households whereas many industrial consumers purchase bulk electricity off centralized high voltage transmission lines.

  - Many large industrial consumers typically use electricity 24 hours a day over most of the year thereby utilizing the electrical system more efficiently.

- The PUB has directed the investor-owned utilities to ensure that electrical rates reflect between 95 percent and 105 percent of the cost of providing service for a particular rate class. The ratio of revenue collected from a rate class to the cost of service is known as a revenue/cost ratio. A revenue/cost ratio of 90 percent means the utility is collecting 90 percent of the cost of service for a particular rate class. This implies that another rate class has a revenue/cost ratio over 100 percent.

- In Alberta, electrical rates of investor-owned utilities only increase as costs increase or the projected load does not materialize:

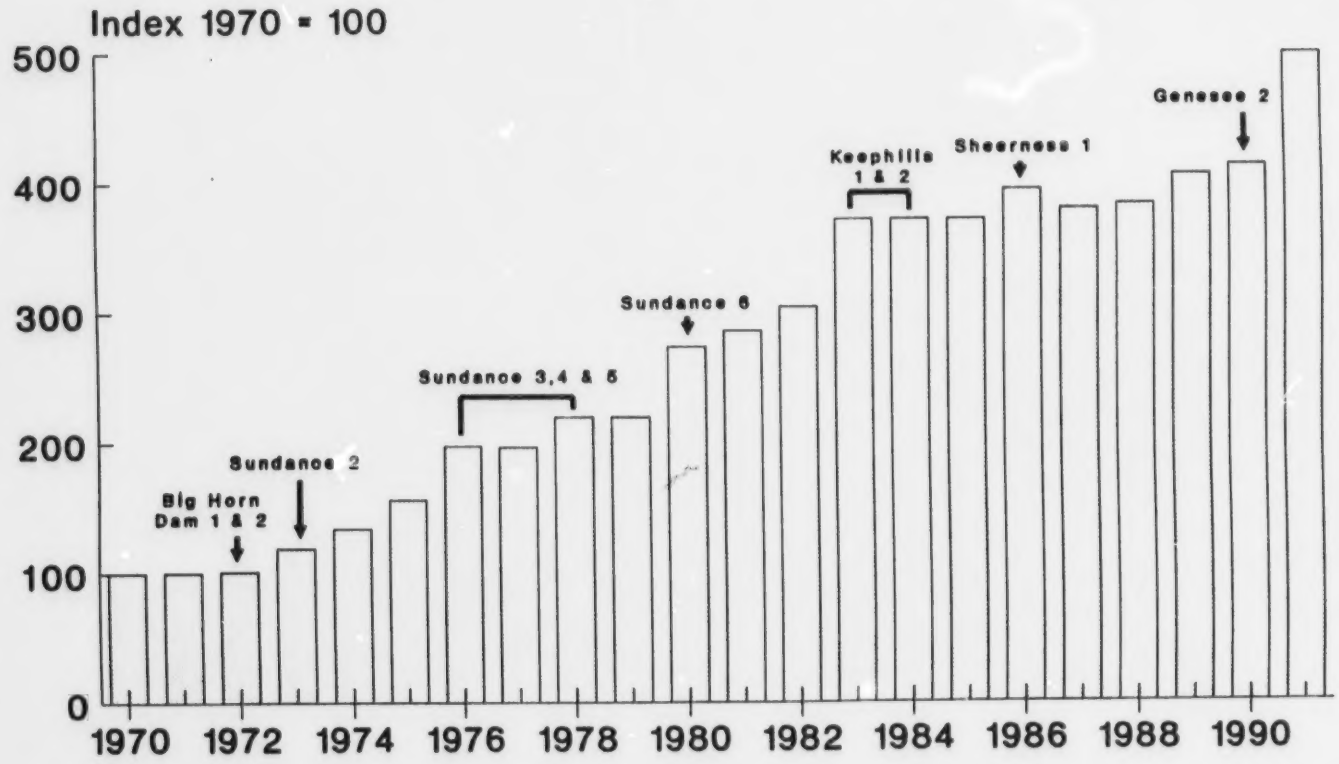
  - Costs increase when facilities are being included in rate base or when operating expenses increase (figure 6). Some crown electrical utilities in other provinces, such as BC Hydro, and some Alberta municipal utilities (for example, Edmonton Power), have scheduled annual rate increases even when overall costs do not increase. This is in order to achieve rate stability.

  - Rates are fixed based on a projected electrical load. If the load is less than projected, the investor-owned utility may experience a revenue shortfall and therefore require a rate increase.

  In the past, Alberta's investor-owned utilities have sometimes had rate decreases as a result of decreasing costs and/or increasing revenue from load growth.

- Alberta's municipally-owned utilities, including those which are distribution utilities, have legislated autonomy in setting electrical rates through City Council. Many municipal utilities utilize electrical rates as a revenue source.

TAU's average electrical bills and timing of plant additions to rate base



- Only the generating plants owned by TAU are shown up to 1982. After the implementation of EEMA, all plants are shown since the costs were shared province-wide. Sheerness 1 is jointly owned by TAU and APL and Genesee 2 is owned by Edmonton Power.
- The impact of Genesee was offset in 1990 by a temporary refund rider.
- GST is not included.

Figure 6

B. Summary Outline of the EEMA Process

EEMA Concept

- An important objective of EEMA, which was implemented in 1982, was to reduce the disparity of electrical rates being charged to similar consumers in different parts of the province.

- Although the details of the EEMA process are complex, the basic concept is to recover the costs of generation and transmission facilities from electrical consumers province-wide -- independent of ownership, franchise boundaries and geographic location. It does not include distribution costs (figure 7). Generation and transmission costs account for 50% of the costs in residential rates and 80% or more of industrial rates. The generation utilities under EEMA are TAU, APL and Edmonton Power.

- The EEMA mechanism is designed with the intent of leaving the utilities' shareholders unaffected.

- EEMA effectively removes the impact that service areas have in determining a consumer's generation and transmission costs. This would also occur under the following circumstances:

  - if Alberta's electrical industry was owned by one electrical utility, or

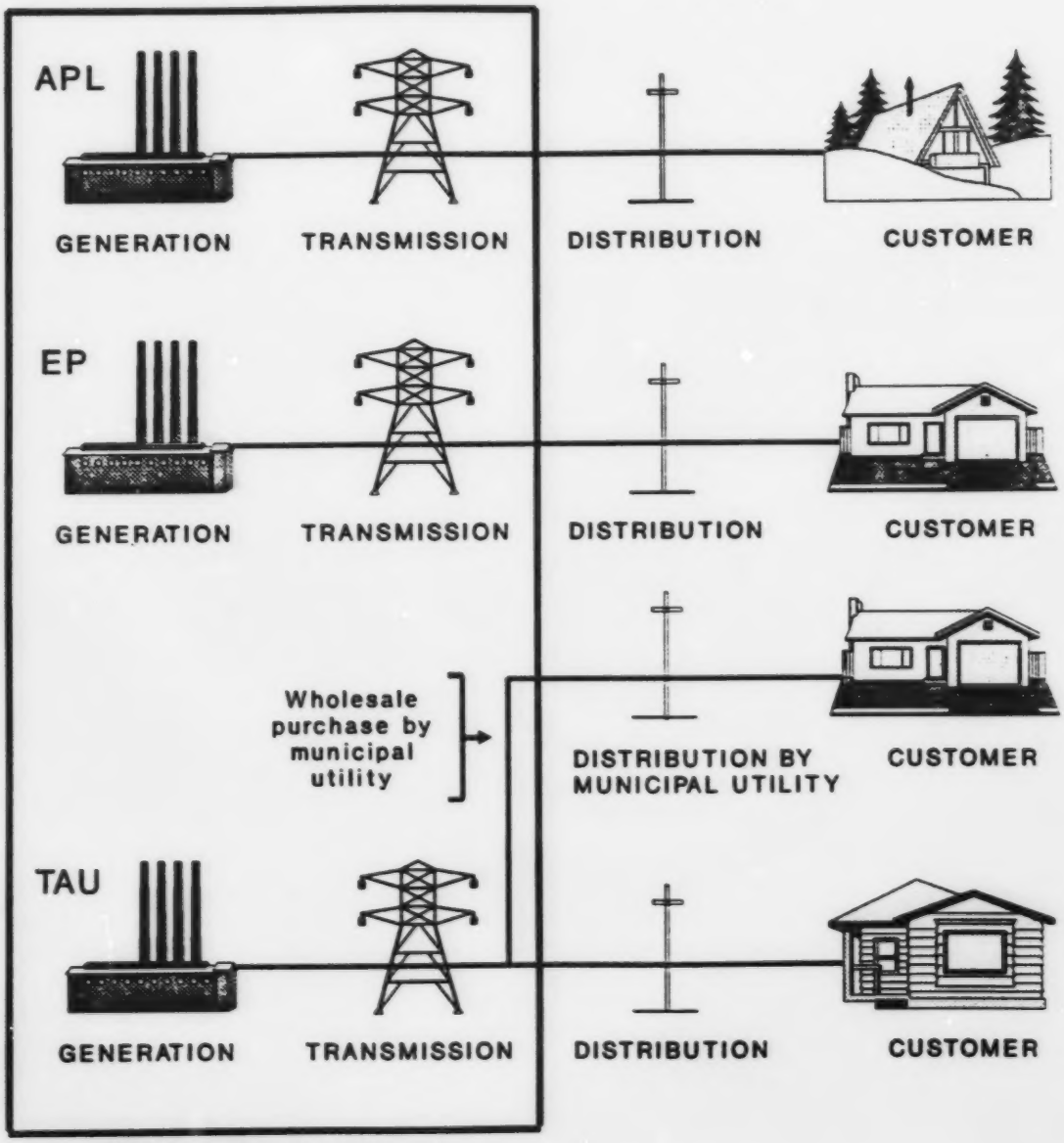
  - if the original establishment of the utility franchises had resulted in service areas with common overall characteristics.

Administrative process

- The equalization of **generation and transmission** costs is achieved by each utility selling its electricity "into EEMA" based on its own generation and transmission costs and then repurchasing the electricity at the average "out-of-EEMA" cost. The difference between a utility's costs "into EEMA" and "out-of-EEMA" reflects the difference in that utility's unit generation and transmission costs and the Alberta system as a whole.

EEMA POOLING CONCEPT

Costs associated with generation and transmission are pooled and the provincial average established.



EEMA Pooled Costs

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ALBERTA DEPARTMENT OF ENERGY
January 22, 1992

- The PUB approves the utilities' costs into EEMA for three separate consumer groups: residential/farm, general service, and large industrial (figure 8). For the general service and large industrial consumer group, costs are further broken down into two categories - energy and demand[7] (defined in the table below). Energy costs represent variable costs for the utilities such as fuel and operating costs. Demand costs represent capital costs of generation and transmission facilities. For the residential consumer group, all costs are classified as energy costs

- These costs are then pooled by the Department of Energy[8] based on the average energy costs per kWh and average demand cost per kW for each consumer group. The utilities then purchase their power back at the averaged cost (figure 9). The difference is passed through to the utilities through an invoicing procedure.

- This procedure is undertaken annually to forecast the transfer payments for the next year. The benefit/cost of EEMA is included in the consumer rates of an investor-owned utility if it has General Rate Application (GRA) currently before the PUB (see "Link between EEMA and the rate setting process"). If a GRA is not before the PUB, any changes in the benefit/cost of EEMA may be passed on to consumers through a temporary rider[9] - referred to as an EEMA Flow-through rider. This ensures the changes in the impact of EEMA are passed through to consumers and not the utilities' shareholders.

- An adjustment is subsequently made to the forecast transfer payments based on the actual load and costs of the utilities. This ensures that consumers are not affected by forecast errors. The adjustments can be passed on to consumers in the form of temporary adjustment riders, as part of the EEMA flow-through rider or included in rates if the utility has a GRA before the PUB.

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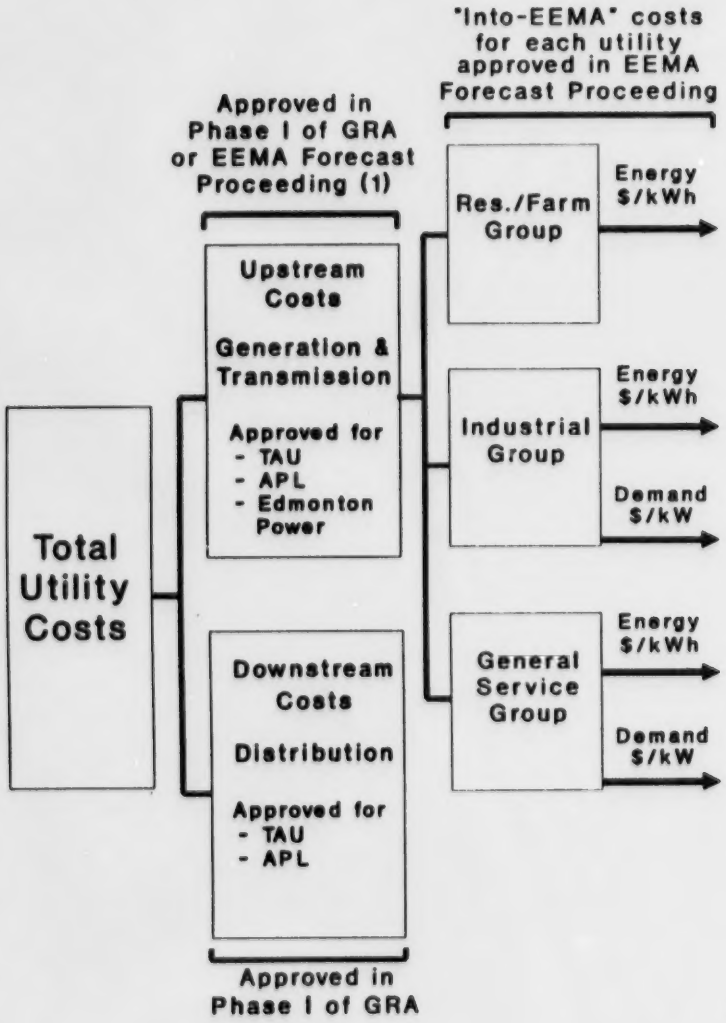
[7] Demand: **Rate** at which electricity flows into a motor or a business. It is also referred to as electrical power and is usually measured in kilowatts (kW).

Energy: Demand measured over a period of time produces a quantity that can be thought of as **consumption**. Electrical consumption is referred to as energy and is measured in kilowatt-hours (kWh). This is because it is the amount of kW multiplied by the duration in hours (kW x hours = kWh).

[8] The administrative process of pooling the costs under EEMA was undertaken by a separate Agency until June 1991.

[9] A rider is a temporary percentage increase or decrease to a consumers rate for a specified period of time. Riders can vary by rate class.

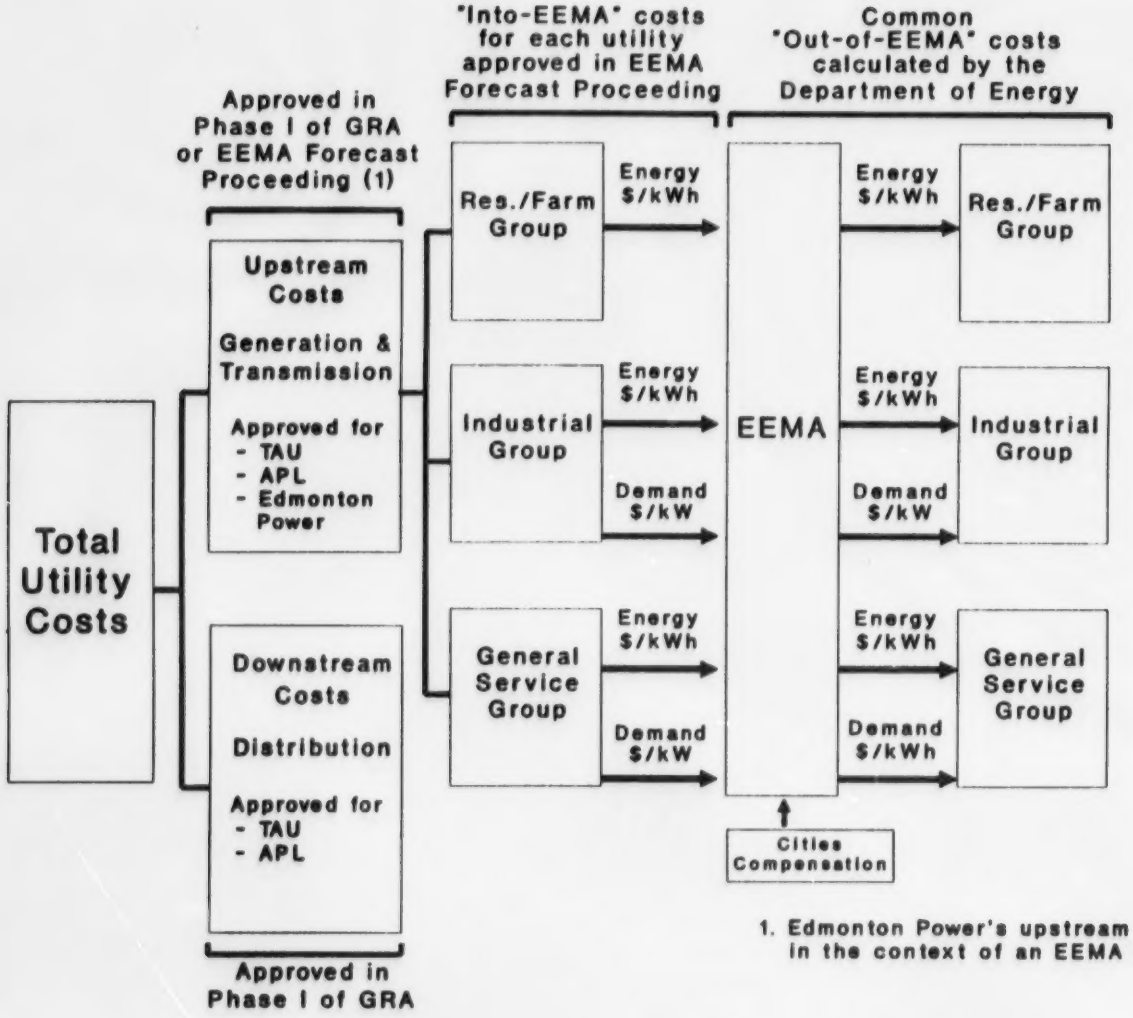
EEMA Process



1. Edmonton Power's upstream costs are always approved in the context of an EEMA Forecast proceeding.

Figure 8

EEMA Process



1. Edmonton Power's upstream costs are always approved in the context of an EEMA Forecast proceeding.

Figure 9

- The EEMA transfer payments in any particular year consist of two components: the transfer payments based on the forecast costs for that year and the adjustments to the forecast transfer payments two years prior. For example, the 1992 transfer payments include the transfer payments based on the forecast upstream costs for 1992 and the adjustments for 1990. The process for 1992 is shown in figure 10.

Cities Compensation

- The Cities of Calgary, Red Deer and Lethbridge own **transmission** facilities with a current annual cost of service of approximately $34 million. Since these costs are not under the jurisdiction of the PUB, they are reviewed by the Department of Energy.

- Payments for these transmission facilities are made to the Cities of Calgary, Red Deer and Lethbridge (referred to as Cities compensation) so that the costs can be included in the EEMA pooling process. A similar result would occur if TAU owned the Cities' transmission facilities -- Cities compensation would be included in TAU's costs "into-EEMA".

- The Cities share in the transmission costs province-wide through TAU's wholesale electrical rate which includes the average cost "out-of-EEMA".

Link between EEMA and the rate setting process

- The benefit/cost of EEMA is passed through to the consumers of the investor-owned utilities when the PUB approves retail electrical rates in the phase II portion of a GRA.[10] The costs "out-of-EEMA" for each of the three consumer groups are allocated based on the energy and demand of the specific rate classes. These costs, and any municipal taxes, are then added to the costs of the utilities' distribution systems (figure 11).

- GRAs occur in a particular year if one is initiated by either the investor-owned utility, consumer interest groups or the PUB. If the utility does not have a GRA before the PUB, then changes in the EEMA benefit/cost are passed through to consumers in the form of a temporary EEMA Flow-through rider until the utility's next GRA.

- The municipalities which own utilities are free to set their own retail rates that include the pooled cost "out-of-EEMA", distribution costs, municipal taxes and profits.

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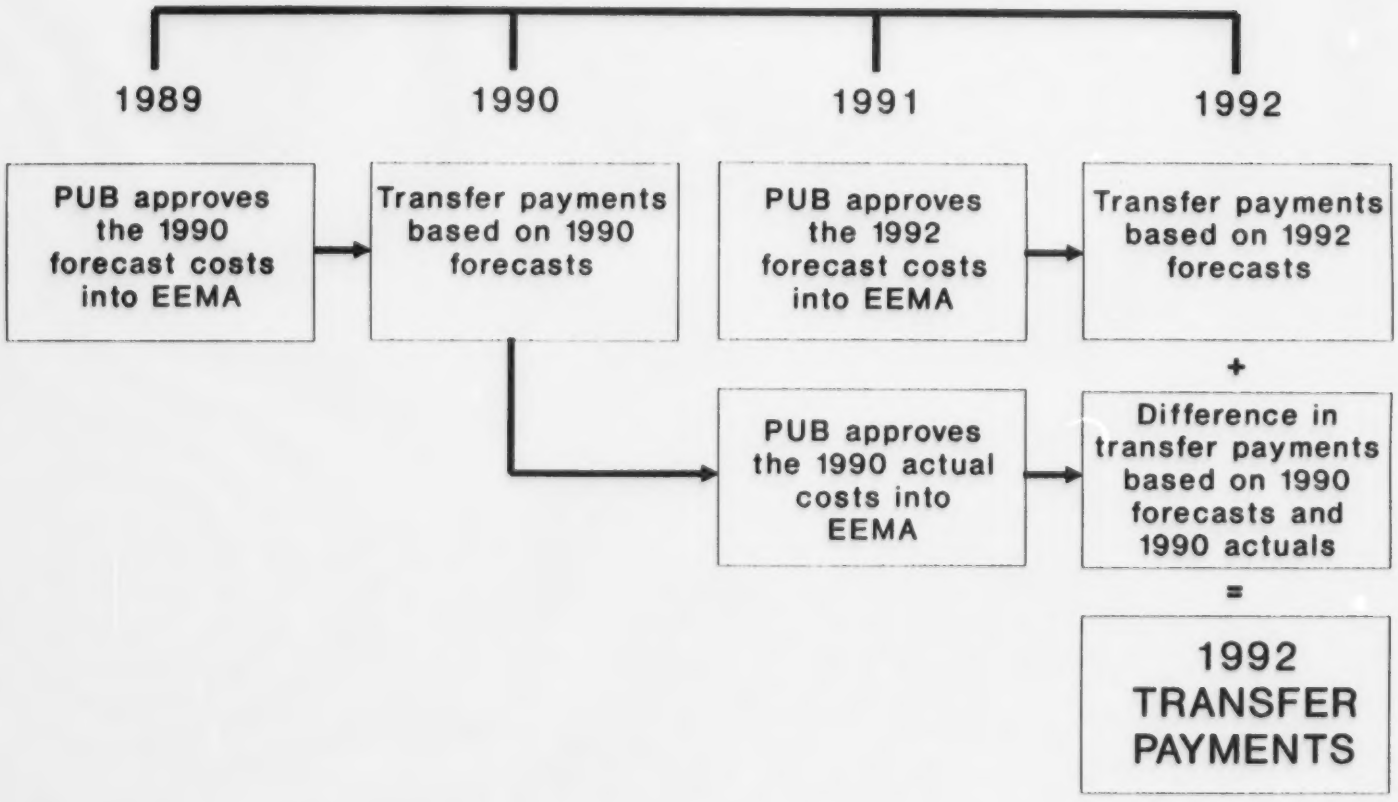
[10] Since Edmonton Power has autonomy in setting its rates (subject to approval by City Council), it can pass through any changes in the benefit/cost from EEMA to consumers.

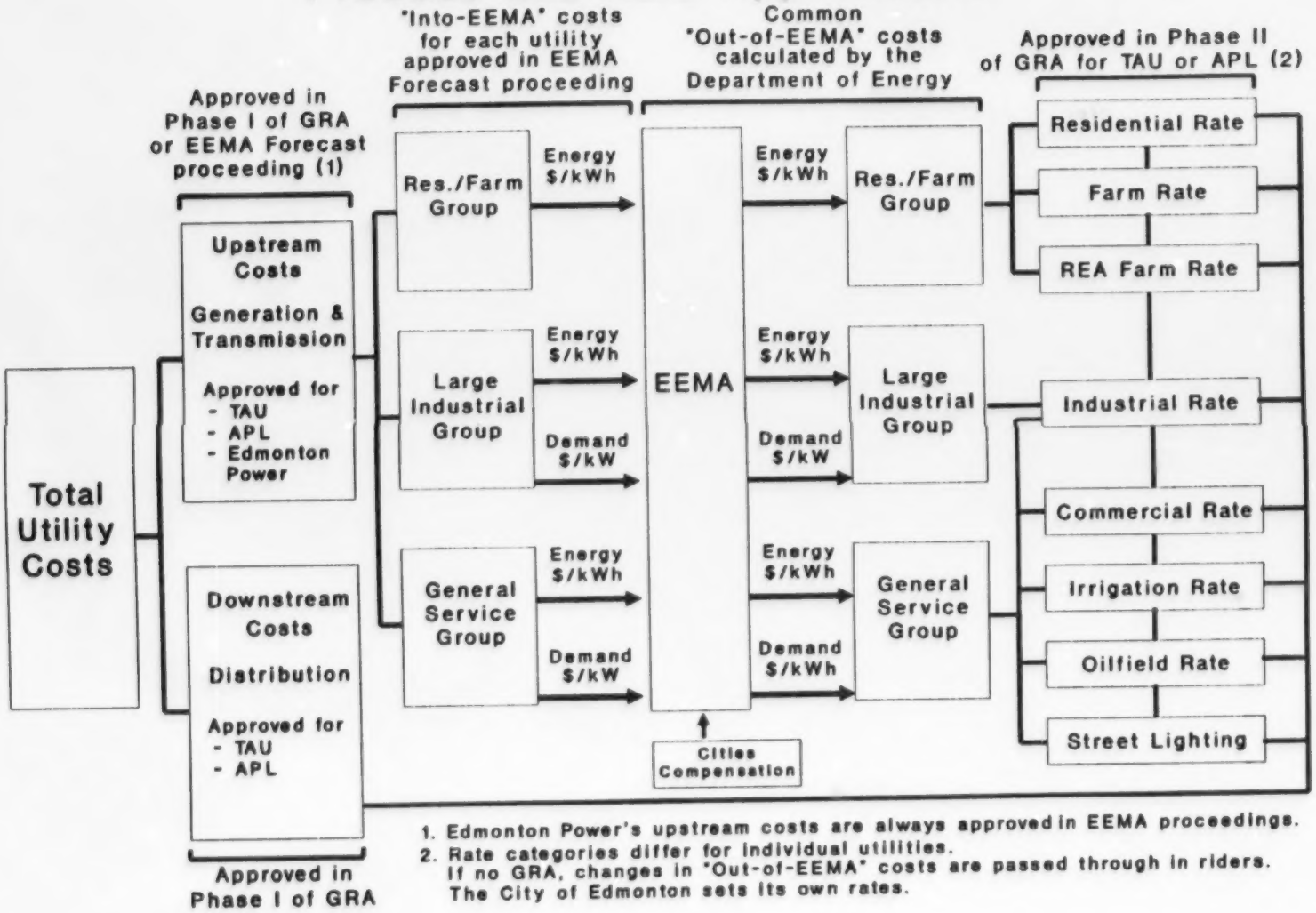
Process to Determine the 1992 EEMA Transfer Payments


1989
1990
1991
1992
PUB approves the 1990 forecast costs into EEMA
Transfer payments based on 1990 forecasts
PUB approves the 1992 forecast costs into EEMA
Transfer payments based on 1992 forecasts
+
PUB approves the 1990 actual costs into EEMA
Difference in transfer payments based on 1990 forecasts and 1990 actuals
=
1992 TRANSFER PAYMENTS

This chart only shows the PUB proceedings connected with the 1992 transfer payments. Each year there is an EEMA Forecast and Adjustment proceeding.

Figure 10

Link Between the Forecast EEMA Process and Rate Applications



1. Edmonton Power's upstream costs are always approved in EEMA proceedings.
2. Rate categories differ for individual utilities. If no GRA, changes in "Out-of-EEMA" costs are passed through in riders. The City of Edmonton sets its own rates.

Figure 11

- The municipally-owned distribution utilities, including the Cities of Calgary, Lethbridge and Red Deer, purchase power from TAU based on wholesale rates that are similar to the average "out-of-EEMA" cost. As a result, generation and transmission costs are similar within each of the three consumer groups whether they are served off the distribution systems of TAU, APL, Edmonton Power or the municipally-owned distribution utilities.

Differences in Electrical Rates with EEMA

- Each utility has its own "investment policy" which sets the amount that the utility will contribute toward the cost of connecting new customers to its distribution system. The lower the contribution towards the cost of connection, the lower the utility's distribution costs and therefore rates. It is important to take into account the consumer's electrical bill and what the consumer had to spend initially to connect to the system when comparing electricity costs between utilities.

- In addition to investment policy, retail electrical bills also vary depending on a number of factors that add to the complexity of comparing consumers' electrical bills. These factors include:

  - timing of rate changes (when rate changes are implemented through a GRA or by City Council);
  - a utility's particular design of rates (e.g differences in revenue/cost ratios);
  - characteristics of the consumer's electrical requirements;
  - differences in municipal taxes; and,
  - the municipal utilities' profits.

  All these factors have to be taken into account when comparing consumers' electrical bills.